Measured Performance of California Buydown Program Residential PV Systems

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ABSTRACT

More than two thousand small grid-tied photovoltaic systems installed in California during the past several years have received partial funding through the California Energy Commission's Emerging Renewables Buydown Program. A sample of these systems have been outfitted with data acquisition systems that collect interval-metered data necessary to characterize system performance. The nineteen monitored systems covered by this paper range in size from 1 to 12 kW, and are located at geographically diverse sites from San Diego County in the South to Willits in the North. Data were collected from February 2000 through the end of 2001.

Key energy production and power output performance issues are treated in the paper, including the importance of explicit definition of the basis of photovoltaic system "size". Both the magnitude and timing of photovoltaic system energy production are covered. Measures of energy production magnitude include energy production per unit of plane-of-array irradiance, and photovoltaic system energy production versus household energy consumption. The magnitude and timing of photovoltaic system power production also are examined. System output coincident with typical weather conditions is estimated and compared to nominal nameplate system size, and average power output levels on peak days are examined. System size actually observed for typical weather conditions was, on average, 62 percent of nominal DC module size. For non-tracking systems, average annual energy production per kW of nominal DC module size was approximately 1,100 kWh/yr.

Introduction

In January 1999 the California Energy Commission (Commission) and Regional Economic Research, Inc. (RER) jointly developed a proposal to monitor in-field performance of photovoltaic (PV) and hybrid PV/small wind systems funded in part by the Commission's Emerging Renewables Buydown Program (Buydown Program). The proposal was submitted to the United States Department of Energy (USDOE) by the Commission. The Commission's proposal, which included provisions for USDOE to fund 50 percent of the project's cost, was accepted and a contract between USDOE and the Commission was executed in mid-1999.

Under this contract, RER monitored key performance parameters of a sample of photovoltaic and/or wind systems for which California Buydown incentives had been distributed. This paper summarizes photovoltaic system findings of Phase I and Phase II of this monitoring project, which includes data collected at nineteen sites. Phase I covered data collected from fourteen PV systems from mid-February through September, 2000. In December 2000 and January 2001 several monitoring systems were moved to new sites, bringing the total number of monitored systems to nineteen. This paper covers data collected at all 19 sites from mid-February, 2000 through December, 2001. While data collection occurred during a period spanning approximately two years, monitoring system moves and other factors contribute to there being varying quantities of data available for the different sites.

Data gathered in conjunction with this project were used to develop information concerning performance characteristics of small PV systems. Performance characteristics addressed in this analysis include energy production, power output, and net impact on utility system loads. Data from this effort were also used by RER to estimate preliminary program-level impacts attributable to photovoltaic systems. Results may also be used by the Commission and USDOE to develop technical and economic program design criteria for future emerging technology commercialization programs.

Sample Selection and Data Collection

Criteria used to select systems for inclusion in the sample of monitored sites included: 1) geographic diversity; 2) variety of system configurations (battery/no battery), equipment (module and inverter brands, models, and quantities), and system sizes (from 1 to 12 kW); and 3) variety of retailers and installation vendors. Key characteristics of the nineteen PV systems covered by this paper are summarized in Table 1. The sites are located from San Diego County in the South to Willits in the North. Several sites are located in coastal areas, while sites located well inland include Grass Valley and Mariposa in the Sierra Nevada Foothills. System sizes indicated in Table 1 are based on total nominal PV module DC power ratings. Rebated system sizes tracked

Table 1: Characteristics of Monitored Sites

Site	PV Mount Type	Battery Storage	No. of Inverters	System Size (DC kW)	Available Data (Months)
1. Orinda	Fixed	No	2	12.00	9
2. Saugus	Manual	No	1	5.82	5
3. Monrovia	Fixed	No	1	2.88	9
4. Los Altos Hills	Fixed	No	1	2.16	9
5. Hermosa Beach	Fixed	No	1	2.16	8
6. San Francisco	Fixed	No	1	2.06	10
7. Hollister	Fixed	No	1	2.06	10
8. Cupertino	Fixed	No	2	1.80	7
9. Orinda	Fixed	No	1	0.90	5
10. Willits	Manual	Yes	1	4.80	9
11. Ben Lomond	Fixed	Yes	1	4.32	8
12. Winters	Tracking (2-axis)	Yes	1	4.32	14
13. Paso Robles	Tracking (1-axis)	Yes	2	4.00	14
14. Cupertino	Fixed	Yes	1	3.12	11
15. San Luis Obispo	Fixed	Yes	1	2.66	14
16. Sunnyvale	Fixed	Yes	1	2.40	9
17. Ramona	Fixed	Yes	1	2.05	12
18. Grass Valley	Manual	Yes	1	1.92	9
19. Mariposa	Tracking (1-axis)	Yes	1	0.96	12

by the program included adjustments for inverter losses and predicted temperature effects. In this paper nominal DC ratings are used to facilitate direct application of results to readily available system size information. These values are based on Standard Test Conditions (STC) employed by PV module manufacturers; namely, 1,000 W/m^2 irradiance, 1.5 air mass, and 25°C cell temperature.

Monitored parameters included: 1) solar radiation (on plane of array); 2) PV module temperature; 3) whole-building electricity consumption (AC kWh) measured near point of interconnection with the utility (main breaker panel); 4) inverter energy output (AC kWh); and 5) photovoltaic array output (DC kWh). The monitoring system platform consists of two dataloggers, each with an internal modem. One logger was used to measure solar radiation and module temperature and the other logger measured AC and DC power quantities. Sensor specifications are summarized in Table 2.

Table 2: Summary of Environmental and Electrical Sensors Used

Parameter	Sensor	Specifications
Solar Radiation	LiCor LI200S/UTA	accuracy ±3% typical
Module Temperature	RTD/Mamac Systems Amp	accuracy ±0.5 °F typical
AC Current	Magnelab Current Transformer	accuracy ±1% to 10% of rated current
DC Current	LEM HTA Series Hall-Effect Transducer	accuracy ±1% entire range

Power Output Analysis and Results

Hourly interval-metered data were used to summarize rates at which monitored PV systems produce electricity. Power output and weather data compiled for this analysis allowed development of information relating power output to weather conditions, thereby enabling assessment and direct comparison of overall performance levels of the monitored systems. The coincidence of electricity production with peak California Independent System Operator (Cal-ISO) system demand is also explored. The Cal-ISO is a not-for-profit corporation that is responsible for operation of the high-voltage electric transmission backbone in California.

Modeling of AC Power Output

Specification of system AC capacity is complicated by the fact that power output varies depending on irradiance level and module temperature. Manufacturers of photovoltaic cells and modules typically rate their products at Standard Test Conditions comprising 1,000 W/m^2 irradiance and cell temperature equal to 25 °C. Resulting power output ratings are often incorporated into model numbers. When actually operating in the field, cell temperatures coincident with 1,000 W/m^2 irradiance levels often exceed 25 °C, which may result in observed power output falling short of nominal nameplate ratings.

Alternative approaches based on weather rather than cell temperatures may be used to develop system capacity estimates that are more representative of actual in-field conditions. One commonly-used alternative rating system was developed by the Photovoltaics for Utility Scale Applications (PVUSA) national public-private partnership. PVUSA Test Conditions (PTC) weather comprises 1,000 W/m^2 plane-of-array irradiance, 20 °C ambient temperature, and wind speed equal to 1 m/s. Cell temperatures coincident with PTC conditions, which will vary from system to system depending on a variety of factors, may be estimated using experimental or theoretical methods.

For each system, interval-metered data were used in regression analyses to estimate actual system AC capacity. Plane-of-array solar radiation and module temperature data were collected for each system. Power output at PTC conditions cannot be estimated directly with these data alone because PTC conditions reference specific ambient weather conditions. Instead, separate models were estimated for PV output versus module temperature and module temperature versus weather conditions. This approach was used to allow estimation of module temperature at PTC conditions. Results of this analysis were used to validate assumptions used in the Commission's calculation of rebated system size.

First, regression models describing system power output as a function of irradiance and module temperature were fit to metered data for each system. Values for the parameters were computed using ordinary least squares regression of the metered data. The regression equation is of the form:

$$P_{idh} = \alpha_i + \beta_i \times I_{idh} + \gamma_i \times I_{idh} \times Tm_{idh}$$

Where:

P_{idh} = Power output (AC) for system *i* on day *d* for hour *h*

α_i = Intercept for system *i*

β_i = Irradiance term parameter estimate for system *i*

I_{idh} = Plane-of-array solar irradiance for system *i* on day *d* for hour *h*

γ_i = Irradiance-temperature interaction term parameter estimate for system *i*

Tm_{idh} = Module temperature for system *i* on day *d* for hour *h*

The temperature effects captured by the regression analysis are fairly small relative to some other factors (i.e., lurking variables) that may influence relationships between measured irradiance and power output. Examples include shading, snow, and equipment/wiring failure. For several sites, available data were filtered to exclude influential data points that appeared to fall well outside the range of values expected to be attributable to the factors included in the regression equation.

Monitored systems were not under constant surveillance. Consequently, specification of regression dataset filters was based largely on engineering judgment. Plots of power output versus plane-of-array irradiance for particular months, hours, and hours within particular months contributed to the analysis. Using these plots it is often possible to infer the cause of atypical power versus irradiance ratios for particular hours. Examples include shading by fixed objects, shading by deciduous trees, and shading of the irradiance sensor by snow.

Parameter estimates resulting from regression analyses were used to investigate the sensitivity of power output to irradiance level and module temperature. The median radiation sensitivity was 1.0 percent of power per percent of solar radiation. The median modeled temperature sensitivity was -0.51 %/°C; values typically ranged from -0.04 to -0.87 %/°C. In one instance, however, power output was found to be more sensitive to module temperature. The PV system owner at Site 9 reports misting the modules with water on hot days to reduce module temperatures. This may be responsible for atypical irradiance and temperature sensitivity results obtained for this site.

PV systems at four sites (6,7,15,17) include amorphous silicon (a-Si) photovoltaic cells. The range of temperature sensitivity for these sites is –0.04% to –0.67% and the average is –0.33%. Some of the variability observed in these results may be attributable to the physical configuration of temperature sensors. Sites 6, 7, and 17 use traditional, framed PV modules. For these systems temperature measurements were made on the back of the module. Site 15 includes building-integrated photovoltaic (BIPV) roofing material. For this system temperatures were measured on the front surface of the module, with the sensor itself shaded from direct sunlight. The temperature sensitivity result for this system was -0.67 percent per °C. The average of the other three amorphous silicon systems was -0.21 percent per °C.

Next, data collected at each site were combined with weather data from a secondary source to estimate module temperatures coincident with PTC conditions. Weather data included in the analysis included plane-of-array irradiance, ambient temperature, and wind speed. Ambient temperature and wind speed were not measured at each site so data from nearby California Irrigation Management Information System (CIMIS) weather stations were used. Values for the parameters were computed using ordinary least squares regression. The regression equation is of the form:

$$Tm_{idh} = \alpha_i + \beta_i \times I_{idh} + \gamma_i \times I_{idh} \times Ta_{idh} + \lambda_i \times I_{idh} \times W_{idh}$$

Where:

β_i = Irradiance term parameter estimate for system *i*

γ_i = Irradiance-temperature interaction term parameter estimate for system *i*

Ta_{idh} = Ambient temperature at nearby CIMIS station for system *i* on day *d* for hour *h*

λ_i = Irradiance-wind speed interaction term parameter estimate for system *i*

W_{idh} = Wind speed at nearby CIMIS station for system *i* on day *d* for hour *h*

Parameter estimates resulting from regression analyses were used to estimate module temperatures actually coincident with PTC weather conditions. Values ranged from 43 to 59 °C. The average result was 52.0 °C (126 °F). All else equal, the median increase in module temperature resulting from an ambient temperature increase from 20 °C (68 °F) to 37.8 °C (100 °F) was 20.2 °C (36.4 °F). The median decrease in module temperature caused by a 100 W/m^2 decrease in plane-of-array solar radiation was 3.4 °C (6.1 °F).

System Size Results

Results of regression analyses were used to calculate estimates of system AC power capacities for PTC conditions of 1,000 W/m^2 and estimated module temperatures yielded by the regression analyses described above. Resulting estimates of measured system size are presented in Table 3. The average deviation between nominal DC system size at STC conditions and measured AC system capacity at PTC conditions was 38 percent of the nominal size. The smallest discrepancy was 30 percent. This deviation is attributable to factors such as wiring, module mismatch, and DC to AC conversion losses, as well as reduced output at PTC weather conditions compared to STC testing conditions. For each kW of nominal DC module capacity, typical AC system power output for 1,000 W/m^2 plane-of-array irradiance (i.e., 1-sun conditions) and 68 °F ambient temperature was 620 Watts. For 1-sun conditions and 100 °F ambient temperature the estimate of typical AC system output falls to 575 Watts.

Table 3: PV System AC Capacities

Site	Nominal DC Size (kW)	Actual AC Capacity: Estimated PTC (kW)	Estimated PTC (%)	Maximum Observed (kW)	Maximum Observed (%)
1. Orinda	12.00	7.92	66%	9.04	75%
2. Saugus	5.82	3.76	65%	4.48	77%
3. Monrovia	2.88	1.86	65%	2.00	69%
4. Los Altos Hills	2.16	1.48	68%	1.73	80%
5. Hermosa Beach	2.16	1.52	70%	1.61	74%
6. San Francisco	2.06	1.26	61%	1.41	69%
7. Hollister	2.06	1.28	62%	1.45	70%
8. Cupertino	1.80	0.96	53%	1.13	63%
9. Orinda	0.90	0.52	57%	0.70	78%
10. Willits	4.80	2.53	53%	3.23	67%
11. Ben Lomond	4.32	2.53	59%	2.82	65%
12. Winters[1]	4.32	2.74	63%	3.18	74%
13. Paso Robles	4.00	2.48	62%	2.91	73%
14. Cupertino	3.12	1.99	64%	2.27	73%
15. San Luis Obispo	2.66	1.59	60%	1.84	69%
16. Sunnyvale	2.40	1.36	57%	1.58	66%
17. Ramona	2.05	1.34	66%	1.51	74%
18. Grass Valley	1.92	1.18	61%	1.30	68%
19. Mariposa	0.96	0.55	57%	0.64	67%
Mean	3.28	2.04	62%	2.36	71%
Median	2.40	1.52	62%	1.73	70%

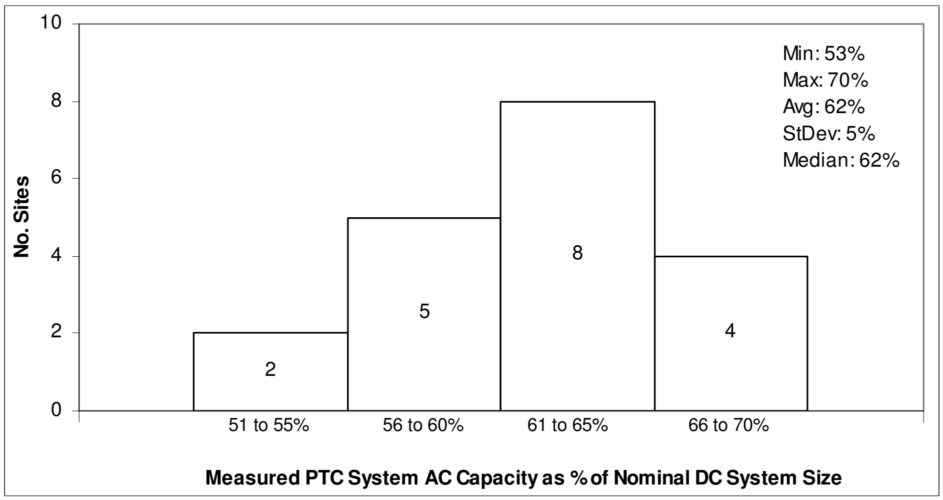
Discussion of System Size Results

Results of the analysis of PTC versus nominal system size are depicted graphically in Figure 1. For this distribution, the average ratio of measured to nominal DC system capacity is 62%. There are many ways to rate system output and it is important that system integrators and customers base their claims and expectations on consistent bases. This analysis investigated relationships between nominal system capacities and estimates of system capacities at PVUSA Test Conditions. These relationships are just one of several that have the potential to move system ratings and

[1] Hardware configuration at this site precluded direct measurement of AC power at the inverter. Estimates presented in Table 3 are based on assumed inverter DC to AC conversion efficiency based on results of analysis of data for other sites.

customer expectations into closer agreement. Because PV system power output (i.e., "size") is so strongly influenced by variable weather factors, if the basis of system size values are not clearly specified there is considerable risk of confusion. Simply referring to a "1 kW PV system" is insufficient; at a minimum, the plane-of-array solar radiation and ambient and/or module temperature associated with a value such as this should be presented alongside the size value.

Figure 1: Histogram - Measured PTC Versus Nominal System Size



The relationship between PTC and nominal system sizes has been explored by others in recent years. One such analysis (Thorne & Booth 2001) combined manufacturer-specific inverter efficiency data with published system-loss rules of thumb (Brooks 1999). Results of this analysis suggest a typical PTC versus nominal DC system size factor equal to approximately 67%. The authors explicitly identify the importance of this result with respect to customer expectations and satisfaction.

A second source of data related to actual system size is the Solar Electric Power Association (SEPA), which makes interval-metered data and analysis results available for dozens of monitored photovoltaic systems of various sizes. The monitored systems were installed with support from the TEAM-UP (building Technology Experience to Accelerate Markets in Utility Photovoltaics) program, which SEPA managed. For eleven TEAM-UP systems in California that are smaller than 5 kW, the mean ratio of PTC to nominal DC system size is 69%. The range of values associated with this mean is quite large: 46% to 86%. The median value, 66%, is approximately 6 percent larger than the median value estimated for the systems covered by this monitoring project. Data availability constraints preclude explanation of this deviation.

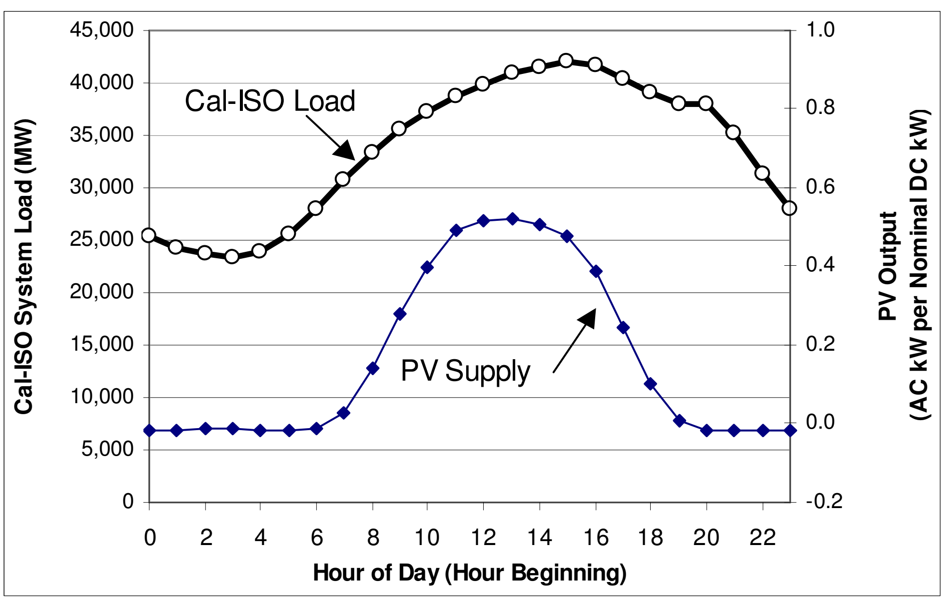
Net Grid Effects

One measure of net grid effects attributable to grid-tied photovoltaic systems is the hourly production profile of those systems on days when electric system demand approaches maximum values. This measure of photovoltaic system capacity benefit is just one of many possible measures, the more rigorous of which would include consideration of the fact that system capacity benefit is a function not only of demand magnitude but also coincidence of available supply and demand. California electric system demand is likely to approach maximum values anywhere between May and October, while renewable system output is by nature variable and seasonal. Interval-metered data for this period are available for the PV systems that were being monitored in the summers of 2000 and 2001. These data were used in combination with Cal-ISO data to develop one measure of the impact of the monitored PV systems on transmission and distribution system peak loads.

First, California Irrigation Management Information System (CIMIS) weather data were used to identify particularly hot summer days. Next, actual Cal-ISO system hourly loads for these days were examined and the hour of system peak was identified. For six days [three in each year] with peak loads exceeding 40,000 MW the system peak occurred during the hour from 3 to 4 PM. The average load during these late afternoon hours was approximately 42,000 MW, which compares to a total Cal-ISO system capacity in the neighborhood of 45,000 MW. Metered data were analyzed to determine the contribution of PV systems to meeting these peak Cal-ISO loads. The coincidence of PV output and Cal-ISO system loads is illustrated in Figure 2.

For the system peak hour of 3 to 4 PM, average PV system output is 0.47 kW per kW of nominal DC system size, which is 91 percent of maximum PV output. Figure 2 illustrates the fact that the potential for PV to help meet Cal-ISO system peaks is sensitive to the time of the peak because the slope of the PV supply line is steep in the region where Cal-ISO system peaks occur. The coincidence of PV output and Cal-ISO loads could be optimized by orienting PV modules toward the Southwest, or by use of tracking systems.

Figure 2: Cal-ISO Load and PV Supply on Summer Peak Days (Typical)



Energy Production Analysis & Results

Several important measures of energy production for the monitored photovoltaic systems are summarized in Table 4. Daily average electricity production (Column A) and plane-of-array irradiance (Column B) are calculated directly from the hourly interval-metered data. Average daily electricity production ranged from 1.2 to 45.4 kWh/day.

Table 4: PV System Energy Production

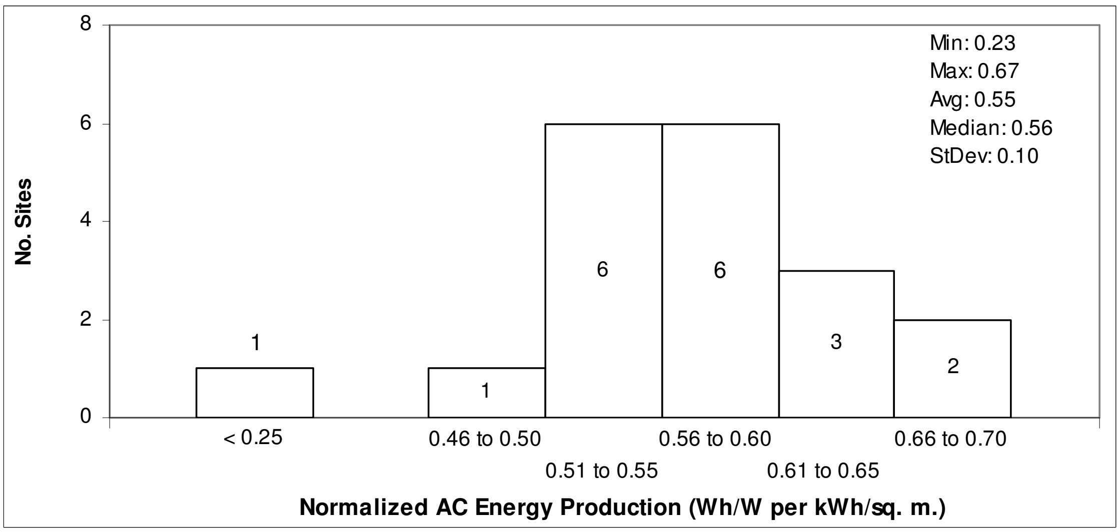
Site	(A) Observed Daily Average Energy (kWh/day)	(B) Observed Daily Average Irradiance (kWh/m^2/day)	(C) Normalized Observed Energy (Wh/W / kWh/m^2)	(D) Assumed Daily Average Irradiance (kWh/m^2/day)	(E) Annualized Energy Production (kWh/Yr/kW)
1. Orinda	45.4	5.7	0.67	5.3	1,293
2. Saugus	26.1	6.8	0.66	5.8	1,388
3. Monrovia	9.3	5.6	0.58	5.5	1,158
4. Los Altos Hills	6.8	5.0	0.63	5.4	1,242
5. Hermosa Beach	7.4	5.2	0.65	5.5	1,306
6. San Francisco	5.7	5.2	0.54	5.3	1,047
7. Hollister	6.0	5.6	0.52	5.3	1,004
8. Cupertino	5.8	6.2	0.52	5.3	1,008
9. Orinda	2.8	5.5	0.56	5.4	1,099
10. Willits	12.7	5.0	0.53	4.6	889
11. Ben Lomond	13.1	5.4	0.56	5.3	1,091
12. Winters	18.2	7.5	0.56	7.6	1,555
13. Paso Robles	18.4	7.3	0.63	7.6	1,740
14. Cupertino	11.0	6.0	0.59	5.3	1,132
15. San Luis Obispo	7.8	5.6	0.52	5.8	1,110
16. Sunnyvale	6.2	5.6	0.46	5.3	892
17. Ramona	5.8	5.4	0.52	5.6	1,065
18. Grass Valley	6.7	6.0	0.58	5.8	1,228
19. Mariposa	1.2	5.5	0.23	7.4	622
Mean	11.4	5.8	0.55	5.7	1,151
Median	7.4	5.6	0.56	5.4	1,110

The considerable variability observed in these results is largely attributable to effects of system sizes, which vary by a factor of more than ten. Observed daily average plane-of-array irradiance values ranged from 5.0 to 7.5 kWh/m^2/day. The two systems exposed to the most solar radiation include automatic tracking systems. The orientation of the system exposed to the next most solar radiation is adjusted manually to improve system performance.

Energy production results normalized by system size and incident irradiance are presented in Column C of Table 4. These data, which are calculated directly from results in Columns A and B, are depicted graphically in Figure 3. Energy production results include effects of battery storage. Energy requirement for "floating" storage batteries is a function of battery type and storage system size, not photovoltaic array size. All else equal, "floating" storage batteries will have a larger influence on overall system performance for systems that include smaller photovoltaic arrays.

A performance measure of particular interest to residential system owners is total electricity production per year. For most of the systems less than one year of data were available. Therefore, to estimate annual energy production normalized AC electricity production results (Column C) were combined with published estimates (Column D) of annual average plane-of-array irradiance for solar collectors (NREL 1994). For each site, information concerning actual system orientation was used to select the annual average plane-of-array irradiance value most representative of actual site conditions.

Figure 3: Histogram - Normalized System AC Energy Output



The annual energy production per unit of nominal DC system size estimates presented in Column E of Table 4 represent one meaningful measure of the variability of system performance. These values range from 622 to 1,740 kWh per year per kW of nominal DC system size. The two systems whose normalized output exceeds 1,500 kWh/Yr/kW are both tracking systems. The average for non-tracking systems is 1,122 kWh/Yr/kW.

Annual energy output estimates presented in Table 4 are based on an important assumption related to the treatment of shading effects of trees and other obstructions. These estimates are based on interval-metered plane-of-array irradiance measurements. In some cases these values include shading effects of trees and other obstructions in addition to those of clouds. Annual average plane-of-array irradiance estimates presented in Column D of Table 4 include shading effects of clouds only, not trees or fixed obstructions. When normalized AC energy output results are combined with these unobstructed annual average irradiance data, resulting annual energy output estimates represent the output for a system free of shading obstructions. While this basis is ideal for developing information for consumer education purposes, in cases where obstruction shading is influential actual output may be less than indicated in Table 4.

Discussion of Energy Production Results

Normalized AC energy production results for the Mariposa site appear to be strongly influenced by battery charging effects. This system consists of a small PV array and a battery storage system that backs up all house loads. While the size of battery storage systems is unknown, it is possible that systems configured in this manner might tend to include larger battery storage systems than those designed to power only a few critical loads when grid power is unavailable. System DC output at this site is seen to compare favorably with performance observed for other systems. System AC net output, however, is significantly less than average due to nighttime battery charging requirements. When considering only those hours when the PV system is generating AC power, the average DC/AC conversion efficiency for the Mariposa system is 81 percent. This result is similar to those calculated for other systems, and it exceeds the overall average efficiency for this site by a factor of approximately two.

As with the power output results, when referencing estimates of normalized energy production it is essential to clearly specify the basis of system size that serves as the normalizing factor. In this paper that basis is total nominal DC module size at STC conditions. This basis was selected because nominal DC module size information is so readily available.

Net Grid Effects

This monitoring program yielded data characterizing the bi-directional exchange of electricity with the utility. This bi-directional flow has at least two important types of results, namely the percentage of the home's load supplied by the renewable energy system and the extent to which the grid actually is being used like a battery. From the perspectives of participants, a meaningful measure of net energy production performance may be the net extent to which electricity produced by renewable means displaces power generated by other means that would otherwise have been purchased to satisfy household electric loads. For each site, this relationship is a function not only of system size but also of lifestyle, appliance types and fuels, number of people in the household, months of measured data available, and weather during the monitoring period. Actual PV system energy production during the monitoring period was summarized in Table 4. During this period, daily average energy consumption for the monitored participants averaged 24 kWh/day, however household energy use varied substantially from participant to participant. Values for particular sites ranged from 9 to 49 kWh/day, as indicated in Table 5. Resulting PV output as a percentage of total household electric energy use ranges from 3 to 139 percent.

Net metering arrangements allow participants to send surplus electricity to the grid during hours when renewable energy system output exceeds the rate of household electricity consumption. One measure of net energy production performance is the extent to which renewable energy system designs and participant electricity consumption patterns result in participants actually taking advantage of net-metering arrangements. During these particular hours participants become net generators of electricity rather than net consumers and effectively use the grid as a battery.

Effects of net metering on bi-directional exchanges with the utility are summarized in Table 5. On average, PV systems deliver electricity to the grid during 47 percent of the hours when they are producing electricity. For the average monitored system, forty-one percent of the electricity that is produced is sent to the grid. For these monitored systems, ability to net meter and use the grid like a battery is very important.

Table 5: Summary of Net Energy Metering Effects

Site	Daily Average Household Electric Use (kWh/day)	Hours Sending Power to Grid (%)	Portion of Production Sent to Grid (%)
1. Orinda	39	56%	60%
2. Saugus	35	58%	50%
3. Monrovia	15	61%	54%
4. Los Altos Hills	16	49%	53%
5. Hermosa Beach	25	48%	36%
6. San Francisco	14	53%	49%
7. Hollister	23	17%	10%
8. Cupertino	12	61%	43%
9. Orinda	15	29%	10%
10. Willits	14	72%	68%
11. Ben Lomond	9	71%	74%
12. Winters	49	33%	46%
13. Paso Robles	28	53%	43%
14. Cupertino	23	60%	48%
15. San Luis Obispo	11	66%	62%
16. Sunnyvale	15	52%	36%
17. Ramona	43	16%	7%
18. Grass Valley	33	36%	21%
19. Mariposa	38	1%	0%
Mean	24	47%	41%
Median	23	53%	46%

Conclusions and Recommendations

Principal conclusions of the monitoring data collection and analysis project concern the actual power output and energy production of small grid-tied photovoltaic systems. System AC capacity actually observed at PTC conditions was, on average, 62 percent of nominal DC system rated size. For non-tracking systems, average annual energy production per unit of nominal DC module size is approximately 1,100 kWh/year. Both of these results are directly related to the basis of the normalizing factor. For this paper total nominal DC module size was used to normalize results because this information is readily available to prospective purchasers of residential photovoltaic systems. Regardless of the particular basis employed, it is strongly recommended that the basis of normalizing factors be clearly defined when normalized estimates (i.e., per unit of system size) are used to summarize PV system performance.

Other important conclusions of the project concern net metering impacts and equipment reliability. Participants are operating their systems in such a way that requires them to send substantial portions of generated electricity to the grid during many operational hours. The ability for the customer to net meter is clearly fundamental to the operation of the monitored renewable distributed generation systems.

As with most energy conversion equipment, small photovoltaic systems are generally not 100 percent reliable. Hardware and software problems may jeopardize system performance, and the performance of several monitored systems changed through time. The tracking system at the Winters site included three separate, independently-operating tracking systems. While details of tracking problems are unavailable, the data suggest that at least two of the trackers experienced equipment problems that reduced system performance substantially. The system installer was notified of the problem and system performance improved a short time later. The manually-adjusted system at the Willits site included unframed PV modules, several of which experienced glass breakage due to unknown causes. At some point in time during the monitoring period the system owner replaced one of the affected modules with a smaller module from a different manufacturer. Finally, the 1.8 kW, 2-inverter system in Cupertino experienced at least two inverter failures that required inverter replacement.

If distributed generation is to play an increasingly large role in the future, its overall reliability improvements will need to be monitored closely. Detailed data collected for this project contributed to problem troubleshooting. It is likely that some fraction of systems not included in this monitoring project will experience similar problems at some time during their long life. To ensure satisfactory performance throughout system life, some level of on-going monitoring of all systems is necessary. Because system output is a function of weather conditions, both electric generation and weather should be accounted for in an on-going performance monitoring plan. Data requirements of such a plan could vary from very minimal to very detailed. The project addressed in this paper entailed research activities with relatively high per-site instrumentation costs. The design of a more widely targeted on-going performance monitoring plan would have to carefully weigh the tradeoffs between the cost of collecting performance data and the value of those data.

Acknowledgements

We gratefully acknowledge the homeowners who allowed us to install and maintain monitoring equipment on their systems. We also thank Bill Brooks, Bob Ramirez, Keith Rutledge, and Dave Fabiszak for their help with data collection, and the USDOE for their support.

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